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Heating Supply Options for Malmstrom AFB, MT

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Foreword

This study was conducted for Malmstrom Air Force Base, MT, under Military Interdepartmental Purchase Requests (MIPRs) No. N341CES0123026, "Reduction of Stack Emissions During Startup and Shutdown at Malmstrom Air Force Base, MT," and N341CES0123027/PO, "Evaluate Air Emission Situation at Base Heat Plant." The technical monitors were William Reid and David Heckler, CES/CEOE.

The work was performed by the Energy Branch (CF-E) of the Facilities Division (CF), Construction Engineering Research Laboratory (CERL). The CERL principal investigator was John L. Vavrin. Dr. Tom Hartranft is Chief, CEERD-CF-E, and L. Michael Golish is Chief, CEERD-CF. The associated Technical Director was Gary W. Schanche, CEERD-CV-T. The technical editor was William J. Wolfe, Information Technology Laboratory. The Director of CERL is Dr. Alan W. Moore.

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1 Introduction

Background

The Coal Fired Heat Plant at Malmstrom Air Force Base (MAFB) is designed to fire natural gas or sub-bituminous coal with a maximum sulfur content of 1 percent. The plant contains three generators to provide high temperature hot water (HTHW) to the entire base. Coal can be burned in two of the generators (Boilers No. 1 and 3), each with an input capacity of 106 million British thermal units per hour (MMBtu/hr) and an output capacity of 85 MMBtu/hr. Natural gas can be combusted in two generators (Boilers No. 1 and 2) at a maximum output capacity of 35 MMBtu/hr per generator, for a total of 70 MMBtu/hr for the two units. Boiler No. 1 can be dual fired on either coal or natural gas. When burning coal, one generator provides ample heat for the entire base with one generator serving as a standby unit. During the spring and fall, natural gas is used to heat the entire base. During the summer months, the entire plant is shut down. The normal time frame for this periodic shutdown is May through September. The U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC/CERL) has a great deal of expertise and experience in researching and troubleshooting problems related to Central Heating Plants (CHPs) and, in particular, coal-fired plants. Based on this experience, MAFB requested technical support in finding the best solution for energy supply and to reduce emissions to meet all permit requirements.

The MAFB Title V Permit, Section III B.9 states that:

> During the start-up periods of boiler No. 1 and No. 3, when combusting coal, the scrubber and baghouse may be bypassed until the exhaust gas temperature reaches 350 degrees Fahrenheit, provided no emission limits are violated (ARM 17.8.715).

During all start-up procedures, the scrubber and baghouse have to be bypassed until the flue gas temperature reaches a level that will not cause damage to the baghouse or cause plugging of the scrubber unit with slaked lime. Emission limits may be exceeded during these start-up periods for up to one-half hour or more. Emission limits may also be violated when the scrubber is bypassed while the plant is operating in order to remove material buildup in the scrubber unit. MAFB may violate their Title V permit during these periods when the air pollution control devices are bypassed. The installation of new equipment, procedures, or changes to the State Implementation Plan (SIP) may provide the means necessary to maintain the heat plant in regulatory compliance at all times. If none of these options is feasible, then alternative fuels and equipment may have to be considered to maintain compliance with base permits. Options considered are variations of natural gas usage with an overall life cycle cost comparison to the existing system.

Objective

The objective of this study was to develop and analyze alternative methods for providing heat to MAFB, and to recommend the best possible alternative that will meet MAFB's heating requirements while maintaining compliance with all applicable environmental permits and regulations.

Approach

In May 2001, MAFB provided CERL with an electronic map of the base and distribution system, as well as building information and boiler logs. CERL researchers used HEATMAP* software to develop and compare the costs of various heating options, including upgrading and decentralizing the existing system. Costs were obtained from the HEATMAP database and the *R.S. Means* cost guides. The costs were increased using an average annual inflation factor to a present cost, and also increased using an area multiplier (for Great Falls, MT). In this case, researchers used a multiplier of 1.2. This multiplier came from Military Handbook MIL-HDBK-1010A, *Cost Engineering: Policy and Procedures* (1 August 1992). From this work, CERL developed the following list of alternatives.

1. **Maintain the existing CHP.** The simplest alternative—and one that always deserved first consideration—would be to continue operating the existing coal-fired CHP, in other words, to "maintain the status quo."

* HEATMAP is a computerized program for analysis of District Heating and Cooling (DHC) developed by Washington State University. Further information on HEATMAP is available through: http://www.energy.wsu.edu/software/HEATMAP/

2. Gas-fired options.

   a. *Replace a hot water generator, the No. 3 boiler*. In this alternative, MAFB would replace the No. 3 boiler and install a 50 MMBtu/hr gas hot water generator. This additional boiler, in line with either of existing gas boilers No. 1 and No. 2 would satisfy the total peak requirement of 85 MMBtu/hr. Either of these two boilers can provide adequate heat (up to 85 MMBtu/hr) for the entire base during extreme cold periods, and heat for potential facility expansions at the base. This option would also allow for one backup boiler. Burners would fire natural gas as a primary fuel and No. 2 fuel oil as a backup (e.g., during a natural gas shortage).

   b. *Install a gas conversion burner on the No. 3 boiler*. In this alternative, MAFB would install an 85 MMBtu/hr natural gas conversion burner, with No. 2 fuel oil as backup in the existing Coal boiler No. 3. The burner would fire natural gas as a primary fuel and No.2 fuel oil as backup. This option also requires Boiler No. 1 to be converted with a 50 MMBtu/hr natural gas conversion burner. Boiler No. 3 could be used as a backup while gas boilers No. 1 and No. 2 would provide adequate heat for the base during extreme cold periods.

   c. *Replacing a hot water generator, the No. 3 boiler*. This option requires exchanging the No. 3 boiler with a new 85 MMBtu/hr gas hot water generator. This option also requires Boiler No. 1 to be converted with a 50 MMBtu/hr natural gas conversion burner. Boiler No. 3 would provide backup to Boilers No. 1 and No. 2, (total capacity of 85 MMBtu/hr). Burners would fire natural gas as a primary fuel and No. 2 fuel oil as a backup.

   d. *Complete decentralization*. This option entirely eliminates the need for a central heating system. New natural gas distribution lines would be installed to each building, which would have its own boiler for heating, domestic hot water (DHW), and/or “process” requirement. Propane would be used as a backup fuel source.

   e. *Central heat plant replacement*. This option requires the complete replacement of the existing CHP with all gas-fired boilers. The existing HTHW buried and above ground pipes will also be replaced with new low temperature hot water (LTHW) schedule 40 direct buried pipes. The existing boilers will be replaced with two 85-MMBtu/hr gas hot water generators. One boiler would be used as the primary boiler, and the other one would be the backup boiler. Burners would fire natural gas as a primary fuel and No. 2 fuel oil as a backup.

Figure 1 shows a summary of these options as a function of boiler heat output.

Malmstrom Air Force Base

Options	Heat Output (MMBtu/hr) Boiler #1	Boiler #2	Boiler #3
Existing	85	35	85
A: Replacing a hot water generator, the No. 3 Boiler	35	35	50
B: Installing a gas conversion burner on the No. 3 Boiler	50	35	85
C: Replacing a hot water generator, the No. 3 Boiler	50	35	85
D: Complete decentralization	0	0	0
E: Central heat plant replacement	85	0	85

Figure 1. Summary of options as a function of boiler output.

Units of Weight and Measure

U.S. standard units of measure are used throughout this report. A table of conversion factors for Standard International (SI) units is provided below.

SI conversion factors		
1 ft	=	0.305 m
1 sq ft	=	0.093 m^2
°F	=	(°C x 1.8) + 32

2 Data Analysis

HEATMAP Analysis

CERL conducted the HEATMAP analysis of Malmstrom AFB from May to November 2001. Figure 2 shows the existing distribution system and surrounding facilities of Malmstrom AFB, modeled by HEATMAP.

HEATMAP provides a comprehensive computerized simulation of the district heating and cooling (DHC) systems, and allows users to analyze the hydraulic and thermodynamic performance of existing networks. HEATMAP will also model proposed systems, expansions, or upgrades. The program will take information related to the study area, production plants, and distribution network(s), then size the DHC system to meet the thermal requirements. In addition, the program can model building loads and determine the environmental impact of various DHC options. The Appendix to this report lists the types of information used as input to HEATMAP.

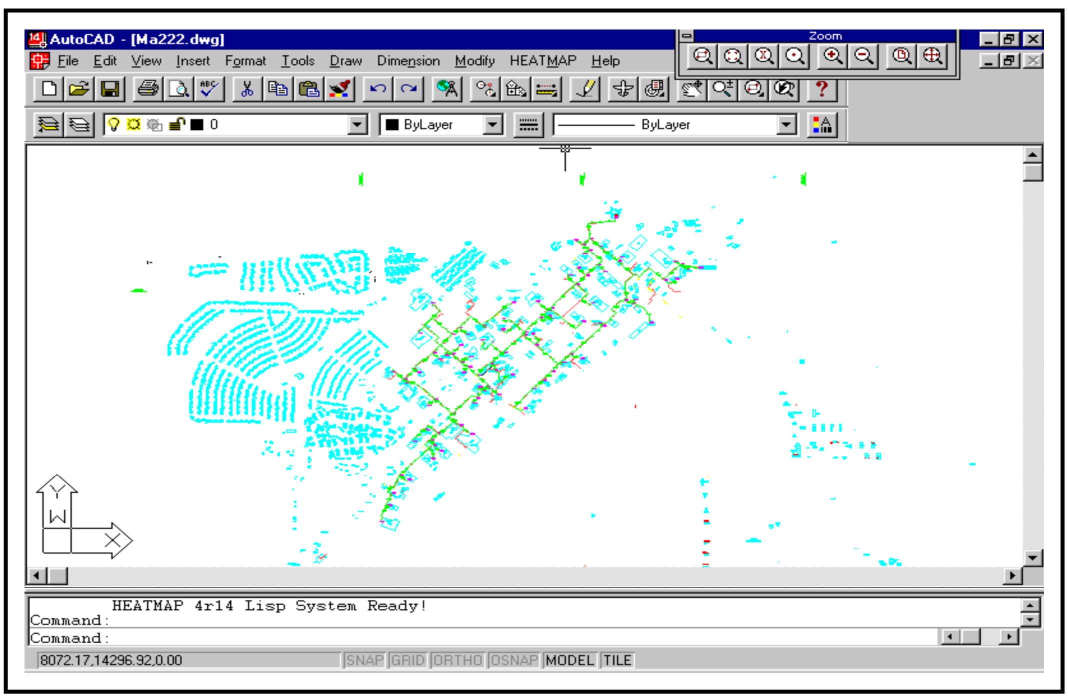

Figure 2. Sample HEATMAP input, Malmstrom AFB, MT.

HEATMAP provides estimates of heating and cooling loads as a function of building characteristics, operating conditions, and climate factors. Climate information from Great Falls, MT was used to model Malmstrom AFB. Figure 3 shows the weather data used for Malmstrom AFB in HEATMAP.

Existing HTHW System

The CHP was built in 1984 and is located in building 82110. It contains three boilers that provide HTHW to the entire base. Coal can be burned in two of the spreader-stoker fired boilers, each with an output capacity of 85 MMBtu/hr. Natural gas can be combusted in two boilers, one of which can be dual-fired on coal. The natural gas servicing the plant enters through a 6-in. line at 54 psig. When natural gas is burned, the maximum output capacity is approximately 35 MMBtu/hr per boiler or a total of 70 MMBtu/hr for the two units. In 2000 the plant operated 273 days. The actual feed water temperature is about 195 °F. Table 1 lists the design data of Boilers No. 1, 2, and 3.

The existing distribution system, constructed in 1984, is an HTHW system with both schedule 80 direct buried and aboveground piping. The water temperature leaving the plant is 363 °F; the water temperature, returning from two separate lines, is 328 and 344 °F. Service pressure is 337 psig for both lines. The system has both supply and return piping. According to base personnel, the existing distribution system has groundwater leaking into the HTHW coffins during the winter months.

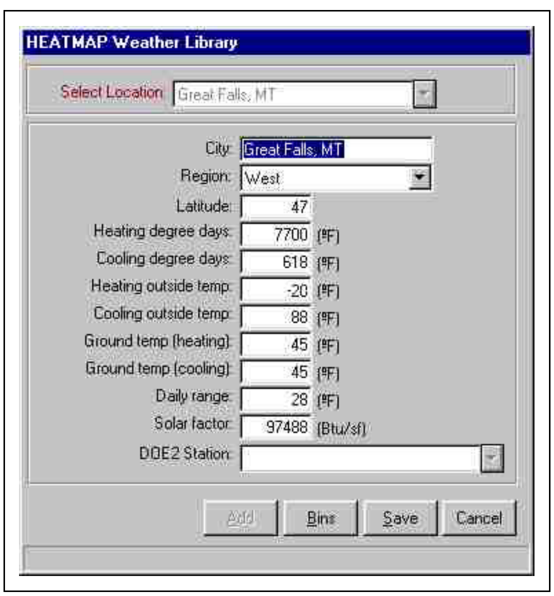

Figure 3. HEATMAP weather input for Malmstrom AFB.

Table 1. Boilers No. 1, 2, and 3 design data.

Building	CHP Boiler Number	Boiler Manufacturer	Output Capacity (MMBtu/hr)	HTHW Conditions Pressure (psig)	HTHW Conditions Temperature (°F)	Fuel
82110	1	International Boiler Works	85/35	337	363	Coal/ natural gas
	2	International Boiler Works	35	337	363	Natural gas
	3	International Boiler Works	85	337	363	Coal

Since the plant is the primary heating source for the base during the winter months, if both coal-fired generators become inoperable, the base mission would be severely impacted. There is the additional danger of the pipes, in many of the buildings, freezing since they do not have the capability of heating themselves.

The current CHP operating procedure calls for one HTHW generator to be operational with the remaining generator acting as a reserve. When the base requires the HTHW, the CHP combusts natural gas until the load reaches 30 MMBtu/hr. Above that point, one of the coal-fired generators is brought online. When the load decreases to 30 MMBtu/hr, the plant switches back to natural gas until the system no longer requires HTHW.

The generator that is on reserve status normally has a nominal flow of hot water circulating through it for preheating. Full flow is established for about an hour before use (time and conditions permitting).

Eighty-two buildings receive heat from the central plant, with a total area of 2,210,890 sq ft. Most of these buildings are over 30 years old.

Table 2 lists the results of an emissions test (measured emissions) completed at Malmstrom AFB in February 2001.

Table 3 lists the most recent coal and natural gas consumptions for the heat plant. Measured boiler efficiency was 81.5 percent. The measured average coal heating value was 12,500 Btu/lb and the measured average natural gas heating value was 890 Btu/scf.

Table 2. Measured emissions of the existing boilers (February 2001).

Boiler No. 1 (Coal & Natural Gas)	Emission Limits	Measured Emissions
NOx	0.50 lb / MMBtu /boiler	0.29 lb / MMBtu
SO_2	0.32 lb / MMBtu / boiler	0.177 lb / MMBtu
Particulate	4.0 lb / hr / boiler	1.047 lb / hr
Opacity	< 20 %	0.00 %
Boiler No. 2 (Natural Gas)	**Emission Limits**	**Measured Emissions**
NOx	0.50 lb / MMBtu / boiler	0.07 lb / MMBtu
SO_2	0.32 lb / MMBtu / boiler	N/A
Particulate	4.0 lb / hr / boiler	N/A
Opacity	< 20 %	N/A
Boiler No. 3 (Coal)	**Emission Limits**	**Measured Emissions**
NOx	0.50 lb / MMBtu / boiler	0.35 lb / MMBtu
SO_2	0.32 lb / MMBtu / boiler	0.192 lb / MMBtu
Particulate	4.0 lb / hr / boiler	1.467 lb / hr
Opacity	< 20 %	0.00 %

Table 3. Coal and natural gas consumption from October 1999 to April 2001.

	Coal (lb)		Gas (1000 cf)			Estimated Total output Boiler eff	
Date	Boiler #1	Boiler #3	Boiler #1	Boiler #2	Total Input Coal+Gas MMBtu/month	eff=0.815 MMBtu/mo	Average output MMBtu/hr
Oct 1999	0	0	19553.4	13796.6	29681.50	24190.42	33.60
Nov 1999	0	0	17587.3	15615.0	29550.05	24083.29	33.45
Dec 1999	0	0	21158.0	18792.0	35555.50	28977.73	40.25
Jan 2000	0	1740909	13279.4	11660.6	43957.96	35825.74	49.76
Feb 2000	0	3049040	0.0	0.0	38113.00	31062.10	43.14
Mar 2000	80048	3025911	0.0	0.0	38824.49	31641.96	43.95
Apr 2000	0	904889	11504.3	9695.7	30179.11	24595.98	34.16
May 2000	0	0	8712.4	12417.6	18805.70	15326.65	21.29
Sept 2000	0	0	0.0	10290.0	9158.10	7463.85	10.37
Oct 2000	0	0	12763.6	18414.4	27748.42	22614.96	31.41
Nov 2000	0	0	22792.6	17347.4	35724.60	29115.55	40.44
Dec 2000	420375	2179172	4504.6	3485.4	39605.44	32278.43	44.83
Jan 2001	2551324	0	575.3	1594.7	33822.85	27565.62	38.29
Feb 2001	113846	2244047	2198.0	3602.0	34635.66	28228.06	39.21
Mar 2001	0	2166803	0.0	4830.0	31383.74	25577.75	35.52
Apr 2001	0	1245062	0.0	13310.0	27409.18	22338.48	31.03

Fuel Costs

The current fuel costs at Malmstrom are $0.0407/kWh for electricity (this figure includes the current demand charge), $72.00/ton for coal, and $0.60/therm for natural gas. Table 4 lists calculated costs per MMBtu.

Table 4. Projected average fuel costs at Malmstrom AFB for 2002.

Fuel	Cost / Them	Cost / MMBtu
Natural Gas (Firm)	$0.60/therm	$6.0/MMBtu
Coal	$72.00/ton	$2.88/MMBtu
No. 2 Oil	$1.01/gal	$7.28/MMBtu
Electricity	$0.0407/kWh	$11.92/MMBtu

Basis for Loads and Losses

CHP logs and fuel consumption reports from the base provided sufficient data for CERL to develop a “best fit” curve to estimate heat loads as a function of outside temperature (Figure 4). Figure 4 shows thermal load from the plant versus outside temperature. HEATMAP presumes that “no-load” heat consumption occurs on a 65 °F day. This no-load condition assumes no heating or cooling, only system losses, a domestic hot water (DHW) load, and any industrial loads. In reality, however, base personnel indicated that the CHP does provide heat to buildings up to about 70 °F outside temperature.

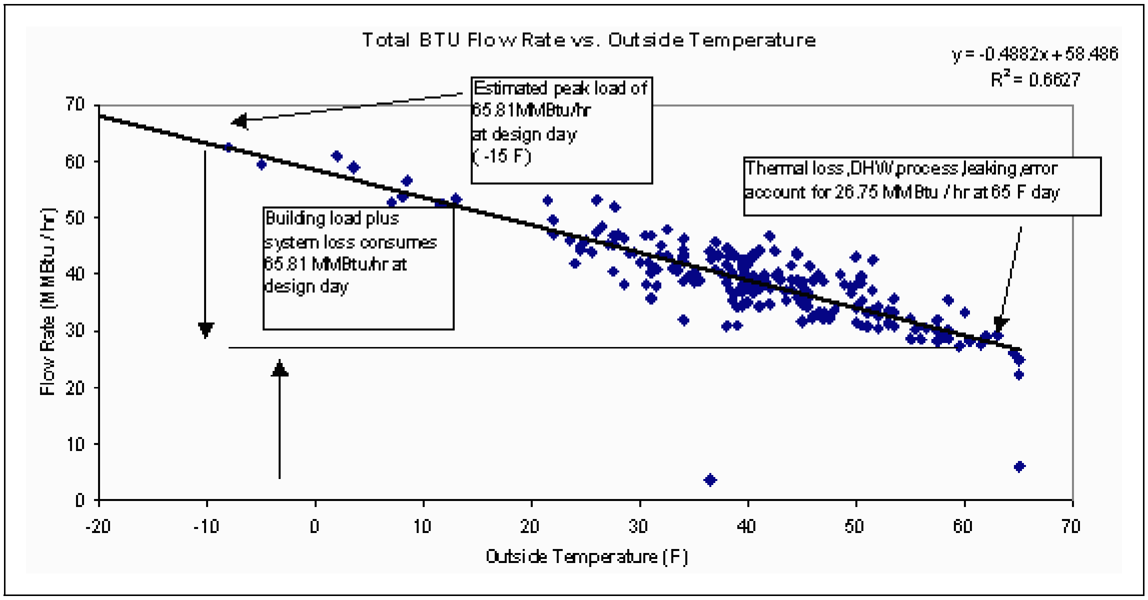

Figure 4. Thermal losses in distribution system, Malmstrom AFB.

MAFB also provides some process heat to 15 steam converters with a total capacity of 58.67 MMBtu/hr. Finally, base personnel stated that there is also about a 5 percent error in plant log data. After discussions with base personnel, CERL researchers estimated these heating loads at the HEATMAP "no load" condition (Table 5).

Figure 4 shows that, at 65 °F, the estimated thermal load is 26.75 MMBtu/hr. The DHW load is estimated at 15,996 MMBtu/yr. Thermal losses due to errors in logs (meters) account for 11,426 MMBtu/yr. Losses in the existing distribution system due to aging, water leaking into the piping coffins reducing insulation effectiveness, and other causes account for about 36,207 MMBtu/yr. This was estimated by taking 10 percent distribution losses for a new system (HEATMAP calculation) and adding 50 percent to that number. In summary, 73 percent of the heat load is used for building and process heating. DHW accounts for about 7 percent of the annual heat output. Errors in logs account for 5 percent. Finally, thermal losses in the existing distribution system amount to about 15 percent of the actual heat output. To ensure accuracy of HEATMAP, actual MAFB heat plant log data was compared to HEATMAP calculations (Table 6).

Figure 4 also shows that the actual peak load is about 62.40 MMBtu/hr for a -8 °F day. At design day conditions (-21 °F), the total consumer peak load for the base is estimated to be 68.74 MMBtu/hr. However, MAFB personnel have indicated that they have had periods of cold weather reaching -40 °F for extended periods of time. At that temperature, MAFB's peak consumer load is approximately 78 MMBtu/hr.

Table 5. Estimated heating loads at 65 °F day (HEATMAP's "no-load" condition).

Type of Heat	Estimated Annual Load (MMBtu/yr)	Estimated Averaged Hourly Load (MMBtu/hr)	% Total Load
Building heat	56,585	6.69	25
"Process heat" and control system error	108,301	12.84	48
Domestic hot water	15,996	1.87	7
"Error" in logs	11,426	1.34	5
Losses: distribution system, leaking, and others (HEATMAP calculation of new system + 50%)	36,207	4.01	15

Table 6. Comparison between the plant logs and CERL's HEATMAP model.

Heating Load	Plant Log	HEATMAP	% Difference
Annual Building Load (MMBtu/yr)	56,585	60,800	6.93
Peak Building Load (MMBtu/hr)	39.05	41.43	5.74

3 Study Alternatives

This chapter summarizes the alternatives for providing heat to Malmstrom AFB. Each alternative provided various options. A life cycle cost calculation was done for each option to help MAFB decisionmakers compare the various alternatives.

Maintain Existing CHP (*Status Quo*)

Table 7 summarizes the costs if MAFB chooses to "maintain the status quo" by continuing to use its existing CHP.

Table 7. Cost to maintain the status quo.

Capital Cost	
Production	$0.00
Distribution	$0.00
Total capital cost	$0.00
Operating costs	
Annual fuel (coal and natural gas)	
Estimated	$1,248,090/yr
Actual (FY 2000)	$1,068,982/yr
Annual OM&R	
Estimated	$752,800/yr
Actual (FY2000)	$628,671/yr
Total Operating Cost	
Estimated (based on current year)	$2,000,890/yr
Actual (FY 2000)	$1,697,652`
Life cycle costs (25 years)	$34,251,000
NOx emissions	27.7 tons/yr
SOx emissions	13.15 tons/yr
Particulate emissions	1.14 tons/yr
(Based on projected fuel costs listed in Table 4 and the heating load for year 2000)	

Gas-Fired Options

This alternative involves converting all portions of coal usage to gas. For all options except decentralization, fuel oil is used as the backup fuel because it is cheaper ($/MMBtu) and because the price is less volatile. In addition, heating oil supply is reliable and secure. Note that all references to boiler sizes refer to thermal output.

Option A — Adding a New Gas Hot Water Generator

To burn 100 percent natural gas, this option would replace the No. 3 boiler with a 50 MMBtu/hr gas hot water generator. This additional boiler, in line with either of the existing gas boilers No. 1 and No. 2, will satisfy the total peak requirement of 85 MMBtu/hr. Either of these two boilers would provide adequate heat for the entire base during extreme cold periods and heat for potential facility expansions at the base. This option also allows for one backup boiler. Burners would fire natural gas as a primary fuel and No. 2 fuel oil as a backup fuel. MAFB would also have to construct a fuel oil storage facility and distribution line to the CHP. Burners would also have to be replaced to allow burning for fuel oil. Table 8 lists the costs for Option A.

Table 8. Costs for Option A, "Adding a new gas hot water generator."

Capital Cost (FY2002 values)	
50 MMBtu HTWG (Boiler No. 3)	$2,352,276
Fuel oil storage tank	$955,206
Gas service piping	
Commercial gate to plant	$152,053
Other (controls, etc.)	$107,867
Total production	$3,567,400
Distribution	$0
Total capital cost	$3,567,400
Operating Cost (FY 2002 Values)	
Annual fuel	$1,692,700
Annual OM&R	$589,415
Total operating cost	$2,282,117 /yr
Life cycle costs (25 years)	$45,797,000
NOx emissions	9.85 tons/yr
SOx emissions	0.0 tons/yr
Particulate emissions	0.141 tons/yr

Table 9. Costs for Option B, "Installing a natural gas conversion burner."

Capital Cost (FY2002 values)	
85 MMBtu/hr burner (Boiler No. 3)	$661,496
50 MMBtu/hr burner (Boiler No. 1)	$649,800
Fuel oil storage tank	$955,210
Gas service piping	
Commercial gate to plant	$152,053
Other (controls, etc.)	$107,867
Total production	$2,526,426
Distribution	$0
Total capital cost	$2,526,426
Operating Cost (FY2002 values)	
Annual fuel	$1,692,702
Annual OM&R	$589,415
Total operating cost	$2,282,117 /yr
Life cycle costs (25 years)	$44,823,000
NOx emissions	9.85 tons/yr
SOx emissions	0.0 tons/yr
Particulate emissions	0.141 tons/yr

Option B — Installing a Natural Gas Conversion Burner

Option B would convert to 100 percent natural gas by installing an 85 MMBtu/hr natural gas conversion burner, with No. 2 fuel oil as backup in the existing coal boiler No. 3. The burner would fire natural gas as a primary fuel and No.2 fuel oil as backup during a natural gas shortage. This option also requires Boiler No. 1 to be converted with a 50 MMBtu/hr natural gas conversion burner. Boiler No. 3 could be used as a backup while gas boilers No. 1 and No. 2 would provide adequate heat for the base during extreme cold periods. This option would require MAFB to construct a fuel oil storage facility and distribution line to the CHP. Burners would also have to be retrofitted to allow burning of fuel oil. The boiler design (short-fire box) could possibly prevent the installation and operation of this large burner. A careful engineering analysis is required. (Note that Boiler No. 1 would burn gas and fuel oil only.) Table 9 lists the costs for Option B.

Option C — Replacing an Existing Boiler with a New Gas Hot Water Generator

This option requires exchanging the No. 3 boiler with a new 85 MMBtu gas hot water generator. This additional boiler would provide backup to the existing gas boilers No. 1 and No. 2. This option also requires Boiler No. 1 to be converted with a 50 MMBtu/hr natural gas conversion burner. This option would satisfy the total peak requirement of 85 MMBtu/hr. Burners would fire natural gas as a primary fuel and No. 2 fuel oil as a backup. MAFB would also have to construct a fuel oil storage facility and distribution line to the CHP. Burners would also have to be retrofitted to allow burning for fuel oil. Table 10 lists the costs for Option C.

Option D — Decentralization

This option entirely eliminates the need for a central heating system. New natural gas distribution lines would be installed to each building that would have its own boiler for heating, DHW, and/or "process" requirement. Installation costs of the distribution lines would be approximately $757,732. In buildings with less than 35,000 sq ft, CERL's cost estimate is $65,000 for equipment, conversion, and installation of decentralized units. (This value was based on previous HEATMAP studies completed by CERL) In buildings with more than 35,000 sq ft, the estimated cost is $1.857/sq ft of conditioned area. Separate individual boilers were sized for each building having a process load; currently 15 buildings have steam converters requiring HTHW. Costs for these boilers came from the 2001 Mechanical Engineering Mean's Cost Estimate Guide. Propane would be used as a backup fuel source; costs associated with the construction of the storage facility and piping to the natural gas line is estimated at $1.30 million. If the base wants to run a master meter gas system, they will need to comply with 49 CFR 192 and meet the training and maintenance requirements as a gas system operator. If the base allowed the utility company to install the gas system, a meter would be needed at every building. Table 11 lists the costs for Option D.

Option E — CHP Replacement

This option requires the complete replacement of the existing CHP with all gas-fired boilers. The existing HTHW buried and above ground pipes will also be replaced with new LTHW schedule 40 direct buried pipes. LTHW piping is applied in this option because the hot water generated is used only for heating, DHW, and steam converters. Currently, the steam converters use HTHW to produce steam; this option will require the converters to use LTHW to produce steam. Capital costs for any modification to the convertors are not included. The existing boilers will be replaced with two 85-MMBtu gas hot water generators. One boiler would be used as the primary boiler, and the other one would be the backup boiler. HEATMAP estimated that it would cost $26,260,584 to replace 89,700 linear feet (including supply and return pipe) of new schedule 40 direct buried pipe. MAFB would also have to construct a fuel oil storage facility and distribution line to the CHP. The burners would also be required to burn No. 2 fuel oil for backup. Table 12 lists the costs for Option E.

Table 10. Costs for Option C, “Replacing an existing boiler with a new gas hot water generator.”

Capital Cost (FY2002 values)	
85 MMBtu HTWG (Boiler No. 3)	$3,534,912
50 MMBtu/hr burner (Boiler No. 1)	$649,800
Fuel oil storage tank	$955,206
Gas service piping	
Commercial gate to plant	$152,053
Other (controls, etc.)	$107,867
Total production	$5,399,838
Distribution	$0
Total capital cost	$5,399,838
Operating Cost (FY2002 values)	
Annual fuel	$1,692,702
Annual OM&R	$519,778
Total operating cost	$2,212,480/yr
Life cycle costs (25 years)	$46,418,000
NOx emissions	9.85 tons/yr
SOx emissions	0.0 tons/yr
Particulate emissions	0.141 tons/yr

Table 11. Costs for Option D, “Decentralization.”

Capital Cost (FY2002 values)	
Production	$8,881,466
Propane storage & piping	1,300,000
Natural gas piping	$757,732
Controls	$487,564
Total capital cost	$11,426,762
Operating Cost (FY2002 values)	
Annual fuel	$1,350,337
Annual OM&R	$380,200
Total operating cost	$1,730,537/yr
Life cycle costs (25 years)	$41,918,000
NOx emissions	3.20 tons/yr
SOx emissions	0.0 tons/yr
Particulate emissions	0.05 tons/yr

Table 12. Costs for Option E, "CHP Replacement."

Capital Cost (FY2002 values)	
85 MMBtu HTWG (Boiler No. 1)	$3,534,912
85 MMBtu HTWG (Boiler No. 3)	$3,534,912
Fuel oil storage tank	$955,206
Gas service piping	
Commercial gate to plant	$152,053
Miscellaneous	$107,867
Total production	$8,284,950
Distribution	$26,260,584
Total capital cost	$34,545,534
Operating Cost (FY2002 values)	
Annual fuel	$1,417,753
Annual OM&R	$200,457
Total operating cost	$1,618,210/yr
Life cycle costs (25 years)	$63,375,000
NOx emissions	3.76 tons/yr
SOx emissions	0.0 tons/yr
Particulate emissions	0.05 tons/yr

4 Summary

General Description of Life Cycle Cost Calculations

This study used the Life Cycle Cost in Design (LCCID) economic analysis computer program as a tool to evaluate and rank alternatives for new and existing projects in this work. LCCID was used to calculate life cycle costs and other economic parameters for each alternative.

LCCID incorporates the economic criteria of the Army, Navy, and Air Force for design studies. The basic algorithms and reports in LCCID are recognized as a DOD standard. Since the DOD (therefore LCCID) uses the economic criteria of the Department of Energy (DOE) and the Office of Management and Budget (OMB) in these studies, the user may also be able to use the program for economic studies for several other Federal agencies.

The specific criteria and other guidance embodied in LCCID are:

1. Office of Management and Budget (OMB) Circular A-94 (27 March 1972). A new version of OMB Circular A-94 (29 October 1992) uses discount rates based on the entire study period. Actual discount rate used is also based on the Date of Study. Annual updates are published stating new discount rates for specific dates.
2. Code of Federal Regulations, 10 CFR 436A (25 January 1990). Annual fuel escalation rates are published by NIST (National Institute of Standards and Technology) under sanction by DOE.
3. Memorandum of Agreement (MOA) on Criteria/Standards for Economic Analysis/Life Cycle Costing for MILCON Design (initially signed 18 March 1991) obviated the need for separate criteria in the three services of the Department of Defense (Army, Air Force, Navy). LCCID keeps pace with this agreement and its updates. At the time of this report, the most recent version is dated March 1994. This agreement also references LCCID as the principal computer program for complying with the terms of the agreement.
4. DOD Energy Conservation Investment Program (ECIP) Guidance. This guidance uses the memorandum from item 3 as its basis but also has some qualifying factors for energy conservation projects and specifies its own format.

Summary Data

Table 13 lists and Figure 5 shows life cycle costs for each option. Table 14 lists variations in fuel costs as a function of cost changes. Table 15 lists and Figure 6 shows NOx emission rates for all options. Table 16 lists and Figure 7 shows SOx emission rates for all options. Table 17 lists and Figure 8 shows particulate emission rates for all options.

Table 13. Life cycle costs for each option.

	Existing	Option A*	Option B	Option C	Option D	Option E
	Existing	Adding Gas Boiler Water	Installing Gas Conversion Burner	New Gas Hot Water Generator	Decentralize	CHP Replacement
Building Square Footage Analyzed	2,210,890	2,210,890	2,210,890	2,210,890	2,210,890	2,210,890
Annual Building Heating Load (MMBtu/yr)	56,585	56,585	56,585	56,585	56,585	56,585
Peak Heating Load-Building and DHW (MMBtu/hr)	42.20	42.20	42.20	42.20	42.20	42.20
Annual Heating System Fuel Use (MMBtu/yr)	282,117	282,117	282,117	282,117	225,100	236,274
Annual Distribution Loss (MMBtu/yr)	36,200	36,200	36,200	36,200	0	10,500
Supply & Return Piping (ft)	89,700	89,700	89,700	89,700	0	89,700
Annual Labor, Maint. & Repair Cost ($)	752,800	589,415	589,415	519,778	380,200	200,457
Annual Energy Cost – Gas ($6.00/MMBtu)	837,678	1,692,702	1,692,702	1,692,702	1,350,336	1,417,752
Annual Energy Cost – Coal ($2.88/MMBtu)	410,412	0	0	0	0	0
Distribution Replacement Cost ($)	0	0	0	0	0	26,260,584
Production Replacement Cost ($)	0	3,567,400	2,526,426	5,411,534	10,126,760	8,284,950
System Replacement Cost ($)	0	3,567,400	2,526,426	5,411,534	10,126,760	34,545,534
Net PW-25 Year Cycle ($)	34,251,000	45,797,000	44,823,000	46,418,000	43,185,500	63,375,000

* where:
- Existing = Using the existing CHP
- Option A = Adding gas hot water generator
- Option B = Installing gas conversion burner
- Option C = New gas hot water generator
- Option D = Decentralization
- Option E = CHP replacement

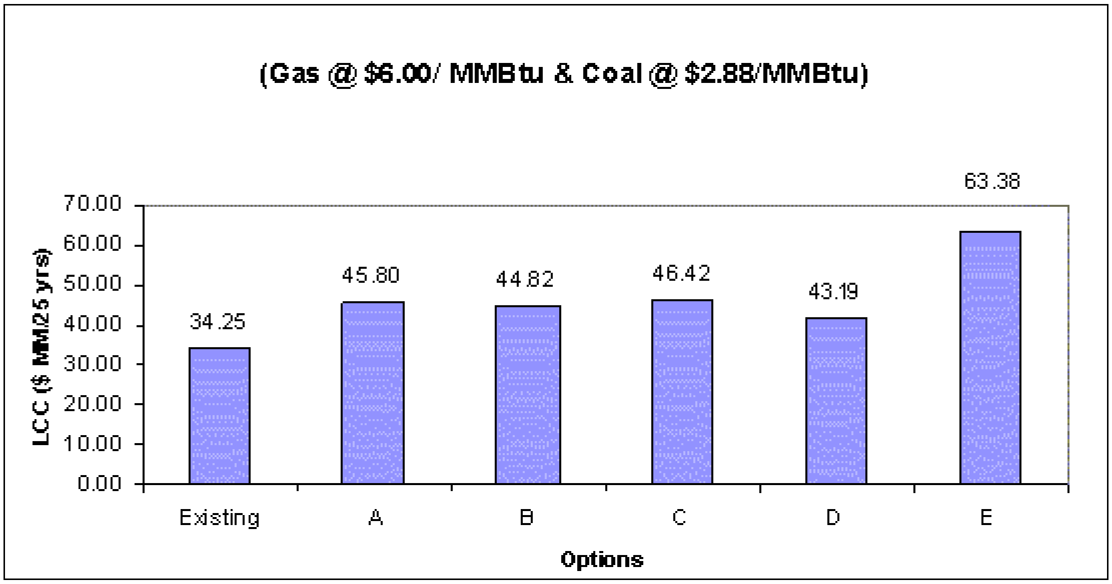

Figure 5. Life cycle costs for each option.

Table 14. Variations in life cycle costs (LCC) as a function of fuel price changes.

	Existing	Option A	Option B	Option C	Option D	Option E
	Existing ($)	**Adding Gas Boiler Water ($)**	**Installing Gas Conversion Burner ($)**	**New Gas Hot water Generator ($)**	**Decentralize ($)**	**CHP Replacement ($)**
LCC Gas $3.50/MMBtu Coal $2.88/MMBtu	27,422,000	31,997,000	31,023,000	32,618,000	32,176,500	51,816,000
LCC Gas $6.00/MMBtu Coal $2.88/MMBtu	34,251,000	45,797,000	44,823,000	46,418,000	43,185,500	63,375,000
LCC Gas $11.00/MMBtu Coal $2.88/MMBtu	47,910,000	73,397,000	72,424,000	74,019,000	65,203,500	86,491,000

Table 15. NOx emission rates summary.

Option*	Name	NOx Emissions (tons/yr)
Existing (Permit Limit)	Permit limit (282,117MMBtu/yr * 0.50 lb/MMBtu)	70.53
Existing	Existing (estimated)	27.69
A	Adding gas boiler-water	9.85
B	Installing gas conversion burner	9.85
C	New gas boiler – water	9.85
D	Decentralization	3.20
E	CHP replacement	3.76

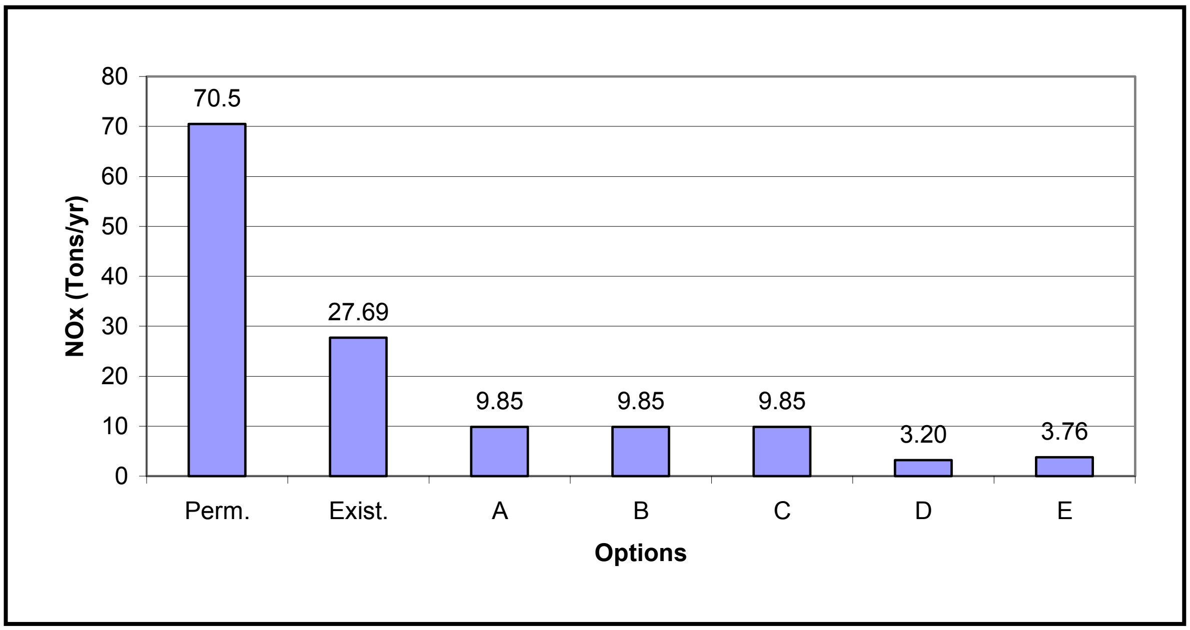

Figure 6. NOx emission rates for all options.

Table 16. SOx emission rates for all options.

Option	Name	SOx Emissions (tons/yr)
Existing (permit limit)	Permit limit (282,117 MMBtu/yr * 0.32 lb/MMBtu)	45.14
Existing	Existing (Estimated)	13.15
A	Adding gas boiler-water	0.0
B	Installing gas conversion burner	0.0
C	New gas boiler-water	0.0
D	Decentralization	0.0
E	CHP replacement	0.0

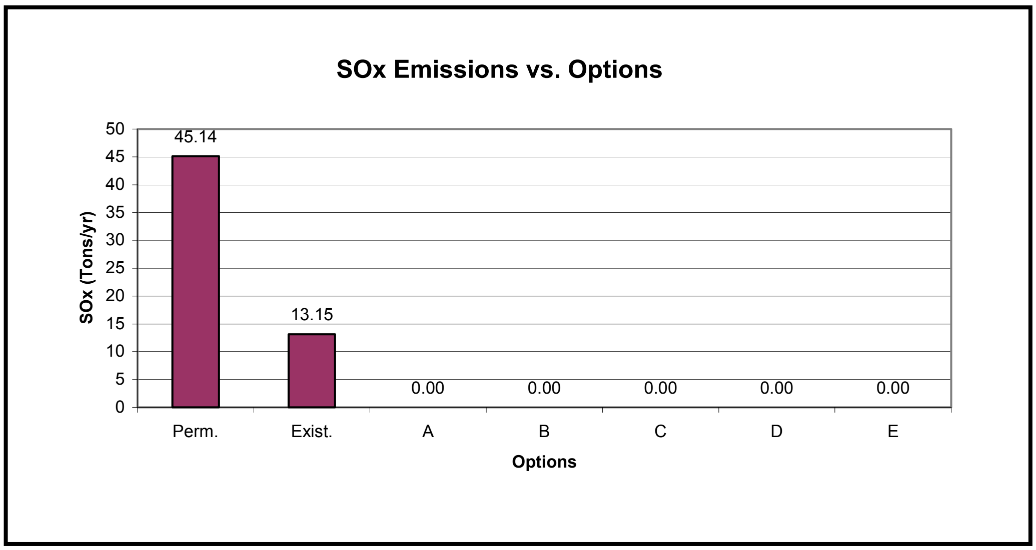

Figure 7. SOx emission rates for all options.

Table 17. Particulate emission rates for each option.

Option	Name	Particulate Emissions (tons/yr)
Existing limit (from permit limit of 4.0 lb/hr)	Calculated Limit (282,117 MMBtu/yr * 0.0377 lb/MMBtu)	5.32
Existing	Existing (Estimated)	1.14
A	Adding gas hot water generator	0.14
B	Installing gas conversion burner	0.14
C	New gas hot water generator	0.14
D	Decentralization	0.05
E	CHP replacement	0.05

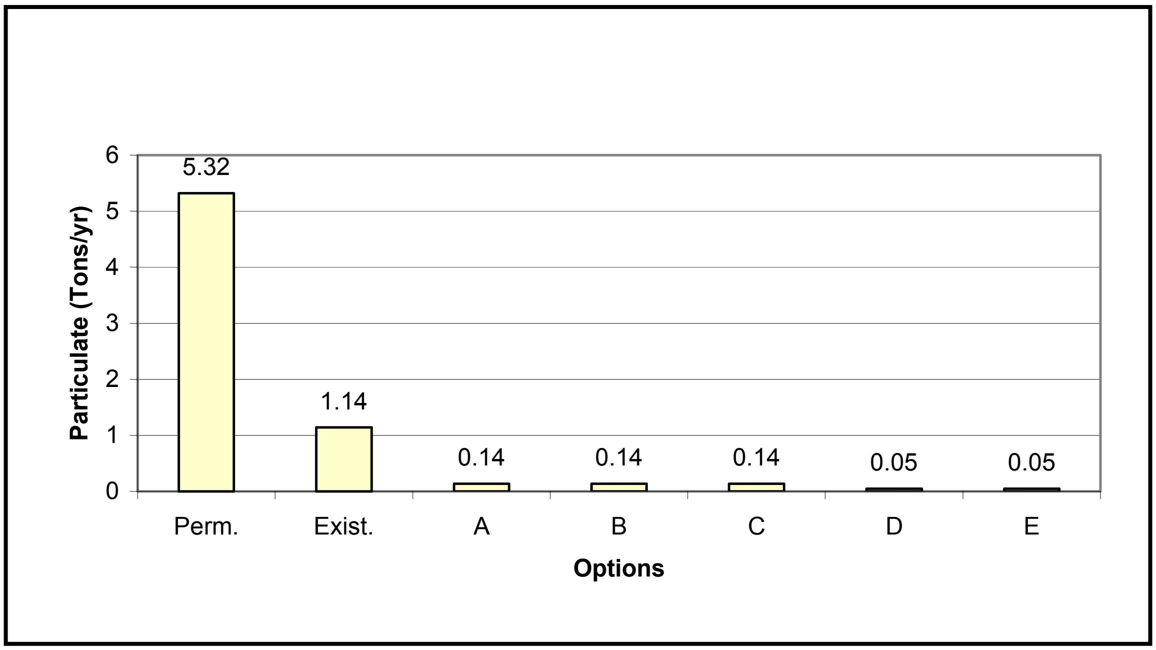

Figure 8. Particulate emission rates for each option.

5 Conclusions and Recommendations

Conclusions

This work has developed several alternative methods ("options") for providing heat to Malmstrom AFB, and analyzed each option to determine its relative merits in terms of maintaining compliance with emissions standards (all applicable environmental permits and regulations), life-cycle cost effectiveness, and general feasibility. The HEATMAP analysis done in this study shows that Option D, "Complete Decentralization," has the lowest life cycle costs of (all gas options) over a 25-year period, and will yield the lowest emission rates of all the options considered. Option D will also completely eliminate the need for a CHP and distribution system. Note that this alternative should only be used if the CHP cannot meet emission standards through facility and/or operational modification.

Recommendations

If the CHP cannot meet emission standards through facility modifications and/or through operational changes, then this study recommends that MAFB adopt Option D, "Complete Decentralization," as the best of the investigated alternatives to their current CHP. A further consideration is that this option will require MAFB to rely solely on natural gas and propane heating fuels. Costs for natural gas fluctuate dramatically. The base must therefore anticipate wide swings in fuel costs, and recognize that there may be a potential for the gas to be cutoff by the utility company. The base could use propane as a backup fuel, which would require construction of a storage facility and a tie-in to the natural gas line.

If MAFB were to maintain its existing CHP, it is recommended that the Base conduct a detailed quantitative engineering study of the CHP's loads and distribution system to quantify its thermal loads and losses. HEATMAP can only estimate thermal losses (cf. Table 6). An onsite survey would quantify these losses and provide a basis for capital improvement spending if the data suggests excessive losses.

Appendix: Input Requirements for HEATMAP

US Army Corps
of Engineers®
Engineer Research and
Development Center

SUBJECT: HEATMAP Requirements

To Our Customers: In order for CERL to complete a HEATMAP study of your installation, we will need the following information:

1. Base Map: An electronic map in AutoCAD Version 14 is preferred. CERL can convert most other file formats to AutoCAD if necessary. Paper maps can be scanned/digitized if electronic maps are not available. The map should include:

Information Needed on Map	**Required for heating system analysis**	**Required for cooling system analysis**	**Optional, but useful**
Heating/boiler plants	✓		
Cooling/chiller plants		✓	
Buildings (consumers) served by the system(s) of interest (including building number)	✓	✓	
Steam and hot water distribution piping	✓		
Chilled water distribution piping		✓	
Natural gas distribution piping	✓	✓	
Roads or other landmarks to assist in locating items associated with the heating/cooling system			✓

2. Installation Information: The following information is needed for the installation as a whole.

Information	Required	Required, but can be estimated
Weather Data: Recommend a city that is comparable to your installation		✓
Costs for all fuels	✓	
Installation electrical utility data showing monthly consumption demand and cost for at least 1 year	✓	
Future planning assumptions—for example, are there plans to construct new buildings, or to deactivate/ demolish old ones? Are new missions expected? Please provide details.	✓	
Energy supply alternatives that you would like us to consider	✓	

3. Building/Consumer Information: The following information is needed for each building that is served by the existing or planned energy supply system.

Information	Required	Required, but can be estimated if not available	Optional, but helpful for analysis
Building Use (e.g., warehouse, barracks, family housing, etc.)	✓		
Total Building Area (sq ft) (not area per floor)	✓		
Total Building Heating and Cooling (conditioned) Area (sq ft)	✓		
Number of stories per building	✓		
Process Loads (if applicable)	✓		
Type of Building Construction		✓	
Year Building was Built			✓

4. Distribution System Information:

Information	Required	Required, but can be estimated if not available	Optional, but helpful for analysis
Heat transfer medium (i.e., water or steam)	✓		
Type of Distribution Systems Currently in Place (direct buried, above ground, shallow trench, etc.)	✓		
Distribution system materials of construction (casing/conduit, insulation, carrier pipe)	✓		
Consumer "delta T" (difference between supply and return temperature)		✓	
Desired Constant Velocity or Pressure Gradient of the System (used for optimum pipe sizing)		✓	
Minimum "delta P" (minimum pressure difference between supply and return piping in the system, usually occurs at the most distant consumer from the plant)		✓	
Summary of recent pipe inspections			✓

5. Plant Information: Information about each heating plant on the installation.

Information	Required	Required, but can be estimated if not available	Optional, but helpful for analysis
Boiler Information: Fuel used, boiler capacity, and number of boilers at each plant	✓		
Temperature and Pressure of Medium (steam or hot water) Leaving Plant	✓		
Boiler Logs	✓		
Results of Recent Boiler Inspections			✓
Average Maintenance Costs for Each Plant		✓	
Plant Labor Costs		✓	
Diversity of Each Boiler*		✓	
* 90% diversity is usually assumed unless otherwise specified.			

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14. ABSTRACT

The Central Heat Plant (CHP) at Malmstrom Air Force Base (MAFB) is designed to fire natural gas or sub-bituminous coal. During the spring and fall, natural gas is used to heat the entire base, and during the summer months, the entire plant is shut down. Emission limits may be exceeded during start-up procedures and when the scrubber is being cleaned. MAFB requested the U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC/CERL) to provide technical support in finding the best solution that will allow MAFB to meet its heating needs while maintaining compliance with emissions standards. This study developed and analyzed several alternative methods, and recommended complete decentralization of the MAFB heating facility as the best alternative to the existing CHP. Of all the considered options, decentralization offers the lowest life cycle costs (for all gas options) over a 25-year period, yields the lowest emission rates, and will completely eliminate the need for a CHP and distribution system.

15. SUBJECT TERMS
Malmstrom AFB, MT; energy conservation; HEATMAP; air pollution control; environmental compliance; Central Heating Plants (CHPs)

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